Action Plan

Better Pricing Signals

Problem Statement

Transmission prices do not provide incentives for transmission users to consider and pursue non-construction alternatives.

Current Situation

When a particular component of the transmission system is overloaded, there are a number of alternatives to building more transmission capacity. Electricity users can reduce their use of electricity or shift their use to off-peak times. End-use customers can install generators and self generate electricity on-site. Generators can build generation closer to the loads they serve and avoid transmission over the overloaded component. But the current pricing system is designed primarily to recover the cost of the existing transmission system, and gives these parties little incentive to consider such actions.

Discussion of issues

There are a number of issues to be addressed before price signals can play a significant part in postponing or substituting for transmission construction:

1. **Retail signals.** Bonneville pricing signals are necessary, but not sufficient in themselves to affect use of the transmission system. Retail prices, or equivalent incentives, do not in most cases convey signals to retail customers where ultimate decisions are made as to when and how much energy is used. Bonneville prices give distribution utilities incentive to pass the signal through to customers, but the utilities may not do so for a variety of reasons.

   A strategy that uses transmission pricing as an alternative to transmission construction would only be effective to the extent that it is compatible with retail pricing. The potential disconnect between wholesale (transmission) pricing and retail pricing is a good example of the institutional barriers that hinder progress toward non-construction alternatives.

2. **Meters.** For retail customers to respond to any signals of conditions whose duration is less than a billing period, they will need meters that can distinguish usage during periods of system stress from usage the rest of the time. Some customers have such meters, many don't.

3. **Dynamic pricing for transmission in the absence of other dynamic pricing**[1]. Under dynamic pricing, transmission prices would reflect the real time conditions

[1] Prices that vary in real time with system conditions e.g. hourly

of the system, which in most hours can accommodate all transmission requests. In most hours the appropriate price for transmission service is a traditional rate designed to recover investment. However, in some hours the system is congested (transmission requests cannot all be accommodated) and a higher price is appropriate.

But congestion pricing for transmission doesn't seem practical in the absence of more general dynamic pricing. If we were thinking about adopting congestion pricing for transmission in a world with dynamic prices for energy already in place, it would be a marginal change for customers. The infrastructure for dynamic prices (meters, billing system, communication) would already be in place. Customers would be accustomed to responding to energy prices every day and they could respond to an occasional added congestion charge for transmission in the same way. But without the larger context of dynamic pricing for energy, it's hard to predict how customers would respond to a very occasional congestion charge applied in a limited geographical area.

4. **Demand charge for NT customers.** Demand charges are sometimes considered as an alternative to congestion charges, but they have their own problems. For most customers, Bonneville's "Network Integration Transmission" (NT) service sets their monthly transmission bill based on their load at the time of Bonneville's transmission system peak, and based on the average cost of the existing system. This provides inefficient prices to customers for 2 reasons: 1) a system component may be at or approaching overload at hours different from the peak load of the system as a whole; and 2) the average cost of the existing system may be a poor approximation of the cost of building a new component.

   Demand charges can be expected to influence peak demand, but to be useful they need to affect transmission use in the right area at the right time (hours of particular stress on particular transmission system components). While the peak demand for the system may not <u>always</u> be in the same hour as the peak demand on the congested section of the system, the two peaks may usually be in the same hour. Furthermore, the conditions that we're most concerned about are those that lead to extreme peaks (e.g. a "Siberian Express") and those conditions may make it even more likely that all components of the system peak at the same time.

   If the hour at which the demand charge is determined matches, or approximately matches, the hour of peak load on the congested section, a "two-tiered" demand charge could be designed. It might charge, for example, $X/kW-month for peak loads up to the highest level observed historically for that customer utility but charge more, say $2X/kW-month for peak load that exceeds that level. This approach would not be as sophisticated as comprehensive dynamic pricing but would provide a useful signal during a period of consideration and development of a more extensive pricing reform.

Tiered rates have been discussed in the past, and they have significant practical problems. Perhaps the thorniest problem is the difficulty of setting the level of load that marks the transition from the "Tier 1" rate to the "Tier 2" rate. This level needs to be set for each customer, with each customer aware that the higher the load threshold for the Tier 2 rate is, the lower the customer's total bill will be. There are many possible formulas (e.g. "Tier 1 rates apply up to a load that is 110% of the customer's peak load over the last 7 years.") and the two rates can be set so that the total of all customers' transmission bills is unchanged. However, it is all but inevitable that for any formula, some customers will feel that they are unfairly disadvantaged because of their unique situation. The result of this difficulty has been great reluctance to revisit the concept of tiered rates.

An alternative to a tiered demand charge would be a fixed adder during hours when the section is congested. A fixed charge would not convey a price signal as precise as a congestion price, but its fixed nature would make it easier for customers to develop response strategies in advance. This alternative is similar to "critical peak" prices for energy.

5. **Price signals for PTP customers.** For other customers, who account for most of the use of Bonneville's transmission system, Bonneville's Point-to-Point (PTP) service specifies a contract level of MW over a specified path. The customer pays a fee ($1.028/kW-month) based on the contract MW as long as the customer doesn't exceed that MW level. If the customer exceeds the contract level it pays an "unauthorized increase" charge, which is double the contract fee per MW. The customer sees a marginal price of using more transmission capacity of either a) twice the contract fee or b) the cost of acquiring short-term rights to capacity from another transmission customer.

   The former, the doubled capacity charge, will be inefficient if the actual cost to Bonneville of providing extra transmission service is different than $2.056/MW-month

   The latter, the cost of acquiring short-term rights from another transmission customer, may or may not be efficient. To the extent that customers exchange short-term rights to transmission in an active market, price signals are generated that give customers incentives to reduce their use of the transmission system, even if they have unused contract rights. If the exchange market is not competitive, however, the prices will not provide efficient signals. Even if the exchange market is competitive, prices will be capped at $2.056/kW-month by Bonneville's penalty fee, so they cannot properly reflect Bonneville costs above that level.

   While the current unauthorized increase charge may not accurately reflect Bonneville's actual cost of marginal service, it has been a point of contention between Bonneville and its customers in the past. Setting the charge at twice the contract fee is common industry practice elsewhere in the country. Bonneville's sense is that even if we knew what level the unauthorized increase charge "should" be, the likelihood of getting acceptance from customers would be poor.

6. **Locational incentives for generators.** A special case of Bonneville transmission customers, generators, are served as PTP customers and are charged at Bonneville's standard rate or the marginal cost for Bonneville to serve them, whichever is higher (the "or test"). This means that generators with high service costs receive efficient price signals. Other generators are charged Bonneville's standard rate with a "Short Distance Discount" for point-to-point distances of less than 75 miles, which can reduce the rate by up to 40 per cent. However, this discount may not reflect the actual benefit a generator's location has for the transmission system, which depends on location relative to congestion, not absolute distance from load. As a result, generators whose location is especially helpful to the transmission system may not receive efficient price signals.

   Based on projects in BPA's generation interconnection queue, it appears that most generators do not place a strong emphasis on locating close to loads. Rather, it appears that proximity to main natural gas pipelines and to water resources is a major driver. Availability of transmission facilities appears to be one of several significant factors in plant siting decisions. Affecting a generator's location decision with transmission pricing could require a substantial incentive.

7. **Pricing incentives to foster accurate forecasts.** BPA customers already have some incentive to overforecast their transmission needs, as we discussed in the Round Table, and there's another workgroup addressing the accuracy of forecasts. There are signs that the problem may be getting worse because folks are submitting high forecasts as a way of establishing rights if and when an RTO is formed and pre-existing transmission rights are allocated. This task group is interested in a pricing scheme that would provide incentives to forecast accurately.

   TBL does forecasts for the majority of its customers; these tend to be small full-requirements customers. Larger publics and IOUs do their own forecasting, and if TBL takes issue with a forecast it has to debate and cajole to arrive at what is perceived to be a realistic forecast. We would like to see TBL examine a pricing mechanism that would send the proper signals to customers to produce the most realistic forecast it can develop. In this way the forecast submitted to TBL would be like a contract between TBL and its customer.

   There are at least two ways of applying the price incentive:

      A. Current payments for transmission could be increased based on the difference between current load and forecast load over time, and could be devised to create a fund that would be used to build transmission to meet the forecasted loads. That is, TBL could begin planning for transmission to meet loads, and charging customers some amount that would enable construction of wires or non-wires solutions when needed, based on the forecast.

Or

B. Price signals could be applied after the fact. In the future, if historic forecasts of present day loads were higher than actual loads by over a certain agreed upon amount (or percentage of load), the forecasting entity would pay an "imbalance charge." In effect, the entities who over forecasted would pay a penalty to help amortize the cost of unused system resources. This again would be fairer than socializing these costs to all, including those whose forecastswere accurate.

There are reasons to prefer 7.A. to 7. B. Among them are that if TBL waited until after the fact, it would probably face politicking from its customers not to apply the penalty charge. Also, the fear of the penalty would be lessened, because the penalty would be discounted, perhaps by many years in some cases.

8. **Buyback programs on peak.** A properly designed buyback can provide many of the same incentives for power users to moderate their demands on the transmission system as the pricing ideas described above. In this approach, customers are rewarded for reductions on peak rather than penalized for consumption on peak, but the economic incentives are comparable. Buybacks could take various forms such as an interruptible contract (the customer is committed to reduce load when the utility needs it) or a demand exchange (the customer can decide whether to respond to the utility's offer on each occasion). An interruptible contract is a more secure resource for the transmission system, but a demand exchange is likely to be more attractive to customers.

Goal

It will take time for us to accumulate the experience with prices and to have confidence in the response. Over time, the response should increase as utilities learn how to translate wholesale prices into retail prices or other effective incentives. Response should also increase over time as retail customers gain experience in adjusting their operations to price variation or incentives, and as customers make investments in equipment to enable them to respond more appropriately to price variation or incentives.

As that experience accumulates, it may be practical to defer construction of added transmission capacity based on the expected response to prices. At our current level of experience, however, most planners would not have enough confidence in price response to support such a deferral of construction. In the meantime, we could implement buyback programs, with which we have a lot of experience. In the long term, more comprehensive pricing reforms may be pursued, taking account of issues described above.

There is much work left to be done before it will be clear whether more accurate price signals provided through a buyback program or transmission pricing can reduce peak loads sufficient to defer transmission expansion. There are primarily three ways to pursue this question.

I. Continue to develop pilot buyback programs in order to assess their ability to defer construction. This would allow BPA to evaluate the effect of different price levels (buyback prices) on actual loads.

II. Explore the possibility of developing voluntary pilot programs for the next Bonneville rate case. These programs could introduce more accurate price signals in order to more fully evaluate the demand responses to prices. It is understood that this would only be useful in those situations where the previously mentioned issues (meters, retail pricing, etc.) are also addressed. The more accurate price signals could take the following forms:

- As an alternative to a tiered demand charge, an adder during hours when loads are high on the stressed section of the system, with day-ahead notice to customer utilities. This would be a form of "critical peak pricing".
- If the level of use of unauthorized increases by PTP transmission customers is low, it is probably not worth a contentious effort to change the level of charge for these increases. Continued monitoring of this use seems worthwhile, in case unauthorized increases become large enough to warrant consideration of modifying the charge.
- Point-to-point transmission customers can currently exchange short-term rights to contract capacity. If this exchange market is active and competitive it can provide price signals that complement price signals from Bonneville. Such a market could provide incentives to customers to reduce their use of transmission even if they have adequate contract rights, since they could receive payment from other customers for doing so. Establishment of a bulletin board for the trading of secondary transmission rights could make this market more active and competitive. There could be revenue impacts for Bonneville that would need to be taken into account, but such impacts should not prevent Bonneville from facilitating this secondary market in transmission rights.
- Price or other incentives for generators that locate where they impose low costs on the transmission system might influence generators' locational decisions.
- Zonal pricing --zonal rates could help forestall new transmission construction if they encourage generators to locate such that they avoid moving power through a constrained portion of the transmission system. Although BPA has not instituted zonal rates, its preliminary analysis for the 2004 rate case could be expanded and, perhaps, implemented in the next rate case. Zonal rates would be based on the long run incremental cost of moving power from one zone to another, where the cost is estimated by the infrastructure costs that would otherwise be required to relieve the congestion. Determining the

optimal number and locations of the zones, as well as the associated avoidable costs, would be challenging, but not impossible.

III. Explore, develop and implement flexible transmission products that can help defer transmission investments. Bonneville's own preliminary work in this area has identified the possibility of new classes of service that might reduce the demand for new facilities. For example, a Conditional Firm product could provide adequate transmission service to certain customers when available transmission capacity is not available in every month. If the customer were to have the equivalent of firm service for, say, 10 or 11 months of the year, they could perhaps rely on non-firm service for the remainder of the year. In such an instance it might be possible to avoid adding transmission capacity. As it stands now, Available Transmission Capacity must exist continuously for the duration of the transmission service request. It is likely that such flexible transmission products could better reflect the demand for transmission service on various paths, thereby providing a better indication of where real congestion exists. (See Appendix for a description of one possible form of flexible transmission service.)

Tasks

1. **Evaluate the feasibility of buyback programs to defer transmission construction**
   Task: Develop and conduct pilot buyback programs similar to the one on the Olympic Peninsula.
   Who: BPA and the NCA Committee
   Due Date:
   Dollars:
   Partners:

2. **Consider a test of transmission pricing to defer transmission construction**
   Task: Develop a pilot program for the transmission rate.
   Who: BPA
   Due Date:
   Dollars:
   Partners:

3. **Consider a zonal pricing option for Bonneville's transmission**
   Task: Flesh out the practical details, identify problems
   Who: BPA
   Due Date:
   Dollars:
   Partners:

4. **Consider the establishment by Bonneville of a bulletin board to facilitate a secondary market in short term rights to unused transmission capacity**
   Task: Estimate the resources needed and costs to Bonneville, including any lost revenues
   Who: BPA

Due Date:
Dollars:
Partners:

5. **Examine the feasibility of charging customers based on their load forecast, or the divergence of loads from historical load forecasts.**
   Task: Develop and vet details.
   Who: BPA
   Due Date:
   Dollars:
   Partners:

6. **Develop Flexible transmission products with the possibility to defer transmission construction**
   Task: Develop product description and test
   Who: BPA
   Due Date:
   Dollars:
   Partners:

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